Raven Energy Ltd.

Annual Report 2001

CORPORATE PROFILE

Raven Energy Ltd. is engaged in the exploration, development and production of petroleum and natural gas in Alberta. Raven's current production consists of natural gas and associated liquids. We will continue to focus our exploration and development activities towards natural gas. Raven's shares are listed on the Canadian Venture Exchange under the trading symbol **"RVL"**. At year-end December 31, 2001 there were 19,361,886 common shares listed.

The photographs in the 2001 Annual Report highlight our exploration and development activity on Company operated projects.

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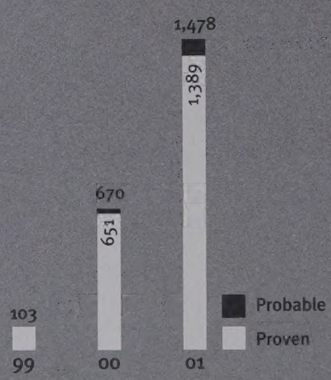
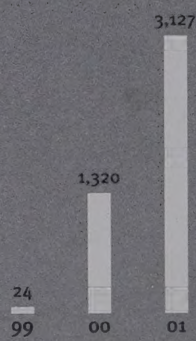
ABBREVIATIONS

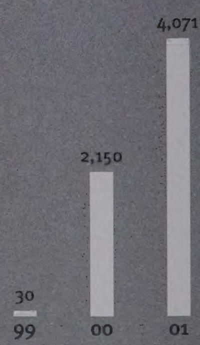
ARTC	Alberta Royalty Tax Credit
bbls	Barrels
mbbls	Thousands of barrels
BOE	Barrel oil equivalent (6:1)
mBOE	Thousands of barrels oil equivalent (6:1)
mcf	Thousand cubic feet
mcf/d	Thousand cubic feet per day
mmcf	Million cubic feet
mmcf/d	Million cubic feet per day
NGL	Natural gas liquids
NPV	Net present value
F&D	Finding and development



Reserves
(mBOE)



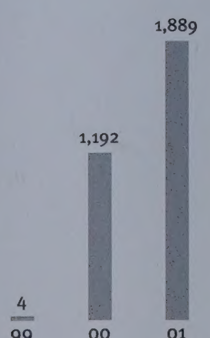
Natural Gas Production
(mcf/d)



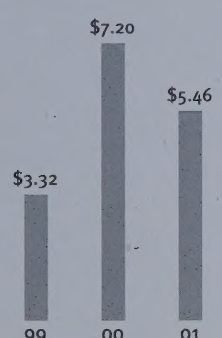
Cash Flow
($ Thousands)

CORPORATE HIGHLIGHTS

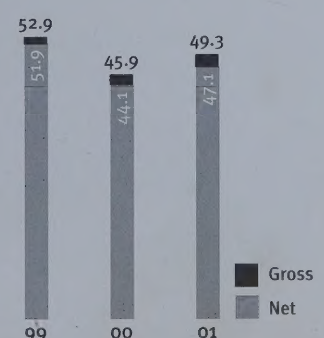
Year Ended December 31 *($ thousands, except per share amounts)*	**2001**	2000
Petroleum & natural gas revenue	**$ 6,228**	$ 3,480
Net income	**1,889**	1,192
Per share, basic & diluted	**0.11**	0.08
Cash flow from operations	**4,071**	2,150
Per share, basic & diluted	**0.23**	0.14
Net capital expenditures	**7,818**	3,355
General & administrative expense	**196**	134
Shareholders' equity	**8,002**	3,480
Debt	**0**	0
Working capital	**549**	952
Natural gas production (mcf/d)	**3,127**	1,320
Barrel oil equivalent (6:1)	**521**	220
Natural gas selling price ($/mcf)	**5.46**	7.20
Operating expenses $/BOE	**3.89**	3.38
Cash flow netback $/BOE	**21.40**	26.69
Proven reserves (mmcf natural gas)	**7,922**	3,903
Proven & probable reserves (mmcf natural gas)	**8,457**	4,016
Proven reserves (mbbls natural gas liquids)	**68.9**	0
F & D costs $/BOE (proven & probable)	**8.11**	5.26
Undeveloped land		
Net acres (thousands)	**47.1**	44.1
Average working interest	**96%**	96%
Common shares		
Weighted average (millions)	**17.8**	15.8
Outstanding (millions)	**19.4**	17.0



Net Income
($ Thousands)

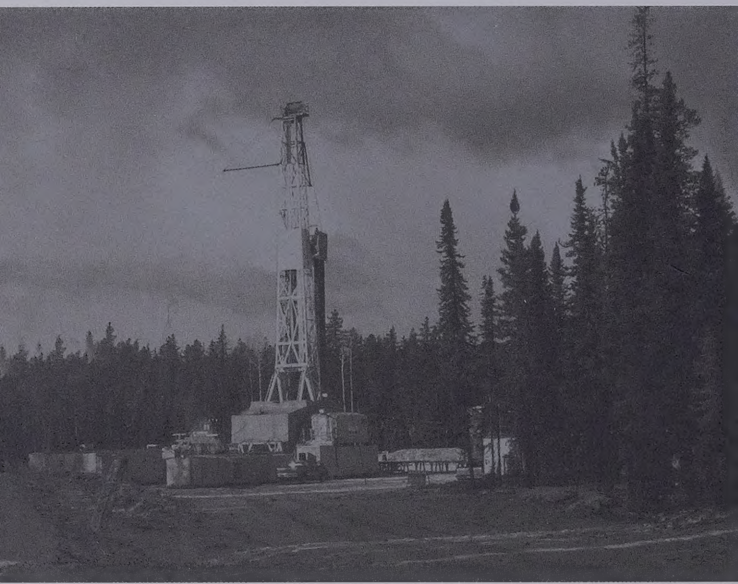


Natural Gas Price
($/mcf)



Undeveloped Land Holdings
(Thousands of Acres)

REPORT TO SHAREHOLDERS



We are pleased to report on the progress of our Company during 2001.

Raven participated in 19 gross (10.6 net) wells during 2001. This drilling resulted in 7.7 net natural gas wells and 2.9 net dry holes. Production during the year averaged 3.1 million cubic feet per day of natural gas. Petroleum and natural gas revenue increased to $6.2 million in 2001 compared to $3.5 million in 2000. This resulted in cash flow of $4.1 million ($2.1 million in 2000) and earnings of $1.9 million ($1.2 million in 2000) for the year ended December 31, 2001.

At year-end December 31, 2001 Raven was well positioned for further growth. Undeveloped land holdings totaled 49,300 gross (47,100 net acres) within the Province of Alberta. Working capital at year-end was $550,000 and the Company had an unutilized line of credit.

During the first quarter of 2002, Raven participated in the drilling of two gross (0.95 net) wells and the re-entry of one (0.9 net) additional well. These wells are located in west central and northwest Alberta, indicative of the Company's trend toward deeper natural gas targets. These drilling activities resulted in one producing natural gas well in the Edson area, one potential natural gas well in the Fir area, and one dry hole at Mearon/Ladyfern. Raven's operations will continue to increase in west central Alberta where the Company believes it has the expertise to pursue and develop long life reserves from liquids rich natural gas.

Raven's objective remains consistent, which is to grow the Company through the drilling of exploration and development prospects. We believe that concentrating in areas where we have experience and expertise will assist us in achieving future success. We will continue to operate the majority of the Company's production, maintain high working interests in internally generated prospects and focus on natural gas. We remain optimistic regarding future natural gas prices and anticipate higher prices in the latter part of 2002 and beyond.

An initial capital budget of $5 million has been established for 2002. These expenditures will be largely financed from cash flow.

Our goals for 2002 are to achieve higher levels of natural gas production and continue to provide growth in shareholder value. We would like to thank our shareholders and directors for their commitment and support.

On behalf of the Board of Directors

Laurie Smith
President and CEO
April 12, 2002

REVIEW OF OPERATIONS

RAVEN COMPLETED ITS MOST ACTIVE YEAR OF OPERATIONS. THE COMPANY CONTINUED ITS PHILOSOPHY OF FINDING, DEVELOPING AND PRODUCING NATURAL GAS. DRILLING OPERATIONS WERE CONCENTRATED IN EAST CENTRAL ALBERTA THROUGH THE FIRST HALF OF THE YEAR AND SHIFTED TO DEEPER DRILLING PROJECTS IN WEST CENTRAL AND NORTHERN ALBERTA BY THE FOURTH QUARTER OF 2001. CAPITAL EXPENDITURES TOTALED $7.8 MILLION, WHICH INCLUDED $1.1 MILLION IN LAND, $1.0 MILLION IN SEISMIC, $3.8 MILLION IN DRILLING AND $1.9 MILLION IN PIPELINES AND FACILITIES.

Drilling operations included participation in 19 wells at an average working interest of 56 percent.The 2001 drilling program resulted in 7.7 net natural gas wells and 2.9 net dry holes for a 73 percent success ratio. Viking remained the most active drilling area, followed by Robin, both of which are located in east central Alberta. Activities during the fourth quarter of the year included participation in deeper wells in the west central area of the Province.

Production during the year was comprised solely of natural gas and averaged 3.1 mmcf/d (520 BOE/d). Reserves increased to 1,478 mBOE consisting of 95 percent natural gas and 5 percent NGL. A total of 94 percent of the reserves are proven. Finding and development costs in 2001 were $8.11 per BOE using proven and one half probable reserves. Netbacks on produced natural gas were $21.40 per BOE. Operating expenses totaled $0.65 per mcf ($3.89 per BOE) largely for processing and compression fees at third party gas facilities. Raven's December, 2001 production rate was 3.2 mmcf/d (535 BOE/d).

Raven's philosophy is to internally generate exploration prospects, maintain high working interests and operate the majority of its drilling and production. The Company has built a production base of shallow gas in the east central area. In 2002, Raven will continue to diversify by developing new gas production in west central Alberta.

Northern Alberta

The Company farmed in on lands in the Mearon/Ladyfern area of northern Alberta. These lands are located several miles from the prolific Ladyfern gas discovery in British Columbia. After purchasing and interpreting 3-D seismic covering the area, Raven drilled a 2,800 metre test well in the first quarter of 2002 targeting natural gas in the Slave Point Formation. The well, in which Raven had a 37.5 percent working interest, failed to encounter hydrocarbons and was subsequently abandoned.

Raven continued to acquire undeveloped lands in 2001. Seismic evaluations are planned for several prospects during the next year.

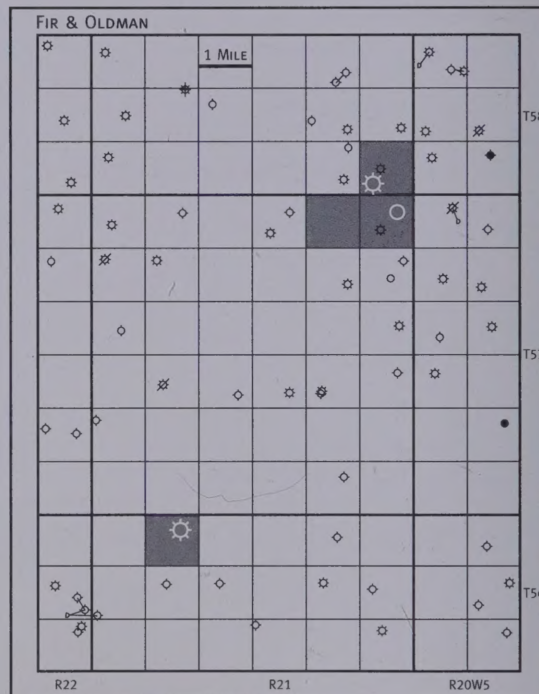
West Central Alberta

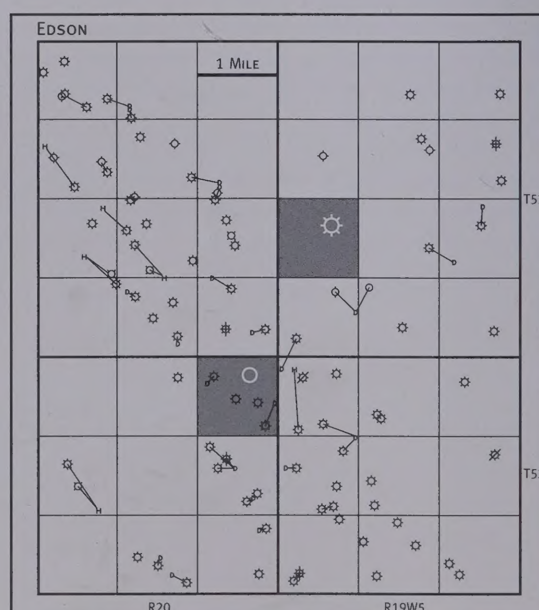
In the second half of the year, Raven began to focus more of its efforts in the west central area of Alberta. In the Oldman area, Raven (50 percent working interest) operated a 2,300 metre re-entry targeting several gas zones. The well was completed as a natural gas well, but remains shut-in awaiting pipeline infrastructure in the immediate area.

The Company (90 percent working interest) recompleted an existing 2,800 metre wellbore as a multizone natural gas well in the Edson area. Operations commenced in December and the well was placed on production in March 2002 at initial production rates of 1.5 mmcf/d of natural gas and 40 barrels of NGL per day.

During the first quarter of 2002, the Company drilled and cased a 2,200 metre well in the Fir area. Raven has a 60 percent working interest in the well. Completion activities are scheduled during the second quarter of 2002.

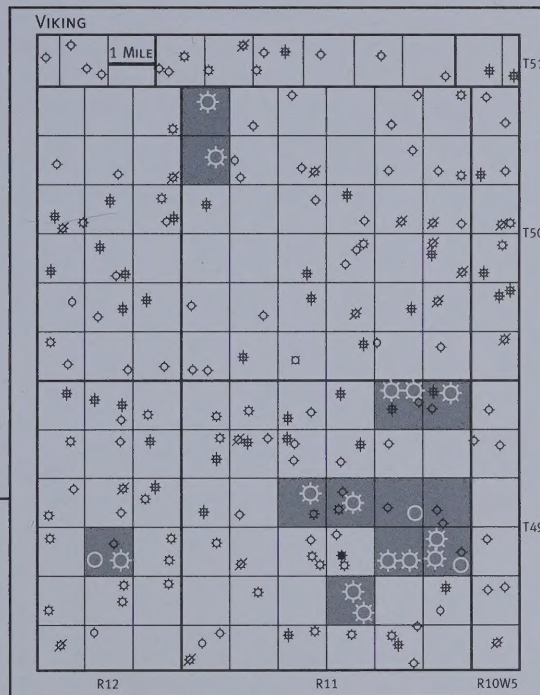
The Company continues to develop drilling prospects for liquids rich sweet natural gas at depths up to 2,800 metres. New prospects have been developed on existing land holdings while others are being pursued through farm-in agreements with third parties and crown land acquisition. While the west central area remains very competitive, Raven believes it can build production with a small but productive team of experienced and dedicated professionals.





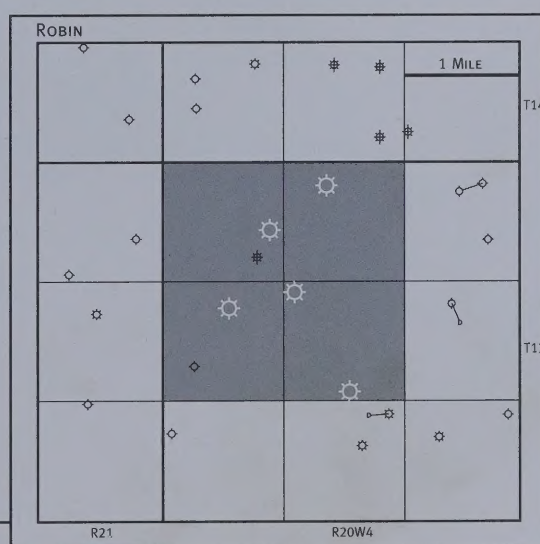
Viking Area

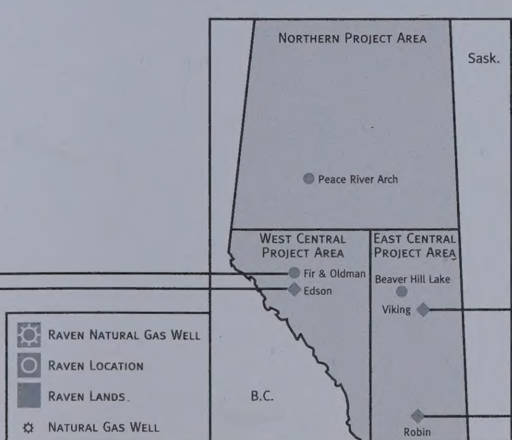
Raven's most active operational area in 2001 was the Viking area. During the year, Raven participated in the drilling of nine gross (6.2 net) wells resulting in seven (4.7 net) natural gas wells and two (1.5 net) dry holes. These wells, averaging 750 metres in depth, were placed on production by year-end bringing the total number of producing natural gas wells to 14 (9.3 net). Daily natural gas production averaged 2.87 mmcf for 2001 with December production at 2.85 mmcf per day. Additional compression was added by the Company to optimize well productivity as pipeline pressures increased due to greater throughput from Raven and other operators in the area. Raven has identified several infill locations that may be drilled in the second half of 2002. The timing is dependent upon available plant, pipeline, and compression capacity in the area. Raven will continue to pursue opportunities at Viking that will enhance the value of this core area.



Robin Area

Robin was developed as a new production area in 2001. Raven has a 40 percent working interest in this non-operated shallow (350 metres) gas property located in southern Alberta. In 2001, the Company participated in the drilling of three wells, resulting in two natural gas wells and the re-entry of four existing well bores resulting in three natural gas wells. Daily natural gas production averaged 235 mcf for 2001 with December production at 365 mcf per day. Compression was added late in 2001 to maintain production in the area.





RESERVES SUMMARY

Sproule Associates Limited of Calgary evaluated Raven's petroleum and natural gas reserves as of January 1, 2002. The following table outlines the estimated reserves and discounted cash values before taxes. The reserves are the Company's gross reserves before royalties using an escalated pricing forecast. Probable reserves were not risked in the Sproule report.

Estimated capital costs of $594,000 are required to place the proven non-producing and proven undeveloped reserves on production. Subsequent to year-end a significant portion of the proven undeveloped reserves (2,065 mmcf and 69 mbbls of NGL) have been placed on production.

Date of Evaluation	Reserve Category	Natural Gas (mmcf)	Oil & NGL (mbbls)	BOE (mbbls)	10% NPV (M$)	15% NPV (M$)
January 1,	Proven developed producing	616	–	103	885	805
2000	Total proven	616	–	103	885	805
January 1,	Proven developed producing	2,799	–	467	7,770	7,133
2001	Proven developed non-producing	562	–	94	769	609
	Proven undeveloped	542	–	90	1,890	1,763
	Total proven	3,903	–	651	10,429	9,505
	Probable developed	113	–	19	171	157
	Total proven & probable	4,016	–	670	10,600	9,662
January 1,	Proven developed producing	4,753	–	792	8,515	7,539
2002	Proven developed non-producing	582	–	97	795	611
	Proven undeveloped	2,587	69	500	5,676	4,752
	Total proven	7,922	69	1,389	14,986	12,902
	Probable developed	535	–	89	576	410
	Total proven & probable	**8,457**	**69**	**1,478**	**15,562**	**13,311**

The following table summarizes Raven's reserves with additions and revisions.

	Natural Gas (mmcf)		Oil & NGL (mbbls)	BOE
	Proven	Probable	Proven	(mbbls)
January 1, 2000	616	–	–	103
Additions	3,641	113	–	626
Production	(483)	–	–	(81)
Revisions to prior estimates	129	–	–	22
January 1, 2001	3,903	113	–	670
Additions	5,083	535	69	1,005
Production	(1,141)	–	–	(190)
Revisions to prior estimates	77	(113)	–	(7)
January 1, 2002	**7,922**	**535**	**69**	**1,478**

*Note: Using a conversion of 6:1 for natural gas in mcf to BOE

LAND SUMMARY

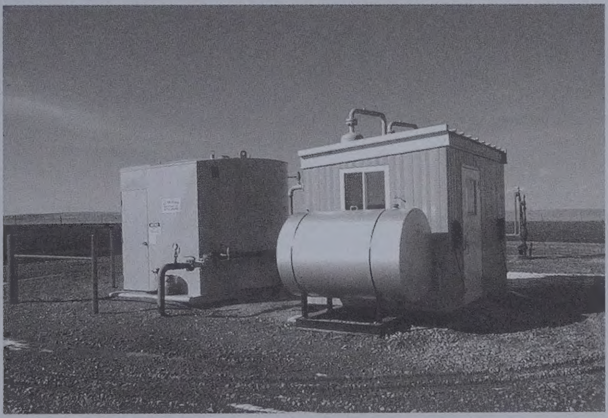
UNDEVELOPED LAND EXPENDITURES IN 2001 WERE $977,059. THE COMPANY ACQUIRED 16,880 NET ACRES AT AN AVERAGE PRICE OF $57.88 PER ACRE. AN ADDITIONAL 1,606 NET ACRES WERE ACQUIRED BY WAY OF FARM-IN AGREEMENTS WITH INDUSTRY THIRD PARTIES.

Raven believes a large undeveloped land base is essential for the ongoing growth of the Company. Raven maintains high working interests in its undeveloped land holdings, all of which are within Alberta. Raven's land position at year-end was 49,320 gross (47,112 net) acres with an average working interest of 96 percent. Raven is well positioned for future growth through exploration and development activity on its undeveloped acreage.

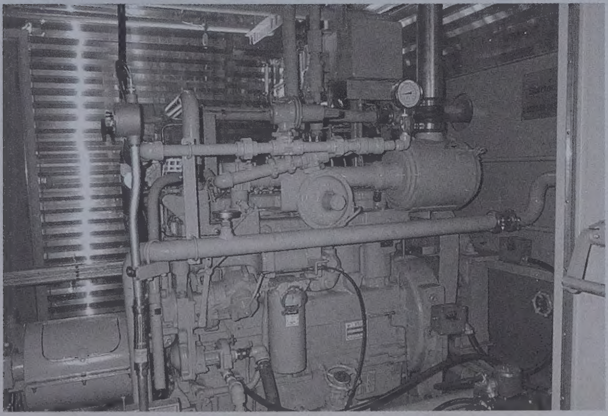
The following table outlines Raven's land position as of December 31, 2001.

Undeveloped Land Holdings (acres)	Gross	Net	Working Interest
December 31, 2000	45,967	44,058	95.8%
December 31, 2001	**49,320**	**47,112**	**95.5%**

An independent evaluation as of December 31, 2001, appraised Raven's undeveloped land value at $2,013,800.



Right: Viking wellsite facility.



Left: Viking compression facility.

MANAGEMENT'S DISCUSSION AND ANALYSIS SHOULD BE READ IN CONJUNCTION WITH THE AUDITED FINANCIAL STATEMENTS FOR THE YEAR ENDED DECEMBER 31, 2001. WHERE AMOUNTS ARE EXPRESSED ON A BARREL OF OIL EQUIVALENT BASIS (BOE), GAS VOLUMES HAVE BEEN CONVERTED TO BARRELS OF OIL AT SIX THOUSAND CUBIC FEET PER BARREL.

The following table provides summaries of Raven's operations for the past two years:

	2001			2000		
Operations summary	**$000's**	**$/BOE**	**%**	$000's	$/BOE	%
Petroleum & natural gas revenue	**6,228**	**32.74**	**100.0**	3,480	43.22	100.0
Royalties	**1,424**	**7.49**	**22.9**	908	11.28	26.1
Alberta Royalty Tax Credit	**(146)**	**(0.77)**	**(2.3)**	(92)	(1.15)	(2.7)
Operating costs	**740**	**3.89**	**11.9**	272	3.38	7.8
Field netback	**4,210**	**22.13**	**67.5**	2,392	29.71	68.8
General & administrative – gross	**351**	**1.85**	**5.6**	215	2.68	6.2
General & administrative – recoveries	**(155)**	**(0.82)**	**(2.5)**	(82)	(1.02)	(2.4)
Current taxes	**5**	**0.02**	**0.1**	150	1.87	4.3
Operating netback	**4,009**	**21.08**	**64.3**	2,109	26.18	60.7
Cash interest	**(62)**	**(0.32)**	**(1.0)**	(41)	(0.51)	(1.2)
Cash flow from operations	**4,071**	**21.40**	**65.3**	2,150	26.69	61.9
Depletion & depreciation	**1,286**	**6.76**	**20.7**	411	5.10	11.8
Future income taxes	**896**	**4.71**	**14.4**	547	6.79	15.7
Net income	**1,889**	**9.93**	**30.2**	1,192	14.80	34.4

Petroleum and Natural Gas Revenue

Petroleum and natural gas revenue increased 79 percent to $6.2 million in 2001, composed entirely of natural gas production. Production increased 136 percent to average 3,127 mcf per day in 2001 compared to 1,320 mcf per day in 2000. Increases in natural gas production were derived from additional wells in the Viking area as well as new production in the Robin area. Production will continue to increase in 2002 with the commencement of production from the Edson area. Production from the Edson area will include both natural gas and associated liquids. Revenue increases resulting from production gains were partially offset by a decline in the average natural gas price realized.

The average sales price received declined 24 percent from $7.20 per mcf in 2000 to $5.46 per mcf in 2001. The Company, from time to time, enters into hedge transactions to manage fluctuations in commodity prices. Petroleum and natural gas revenue in 2001 included gains of $564,000 ($0.49 per mcf) on such transactions. The Company did not hedge any commodity in 2000 and there were no outstanding transactions at year-end. Currently, the Company has contracted an average of 1,865 mcf per day for the period from March 1 to October 31, 2002 at an average price of $3.39 per mcf. The Company does not have any natural gas liquids hedged.

Royalties

Royalties, net of ARTC, on a barrel of oil equivalent basis, decreased 34 percent to $6.72 in 2001 from $10.13 in 2000. This decrease results mainly from lower commodity prices and the price sensitivity of royalty rates. On a margin basis, gross royalties decreased from 26.1 percent to 22.9 percent in 2001 while ARTC received declined 0.4 percent to 2.3 percent in 2001. Approximately one half of the royalties are crown royalties, with the remainder split between freehold royalties and gross overriding royalties. The Company currently receives ARTC on all it's crown royalties, however, on a production unit basis, ARTC declined from $1.15 per BOE in 2000 to $0.77 per BOE. The addition of new production in 2002 will change the composition of royalties paid and should result in a lower royalty burden due to the effect of crown royalty holidays in the Edson area.

Operating Costs

Operating costs increased 15 percent from $3.38 per BOE in 2000 to $3.89 per BOE in the current year. Operating costs have increased over the prior year due to higher third party processing and compression fees on new production as well as the overall increases experienced by the industry in 2001. Operating costs are anticipated to increase in 2002 due to the higher costs associated with the production of natural gas liquids in the Edson area.

General and Administrative Expenses

General and administrative expenses, before overhead recovered by the Company as operator, decreased from $2.68 per BOE in 2000 to $1.85 per BOE in 2001 as costs continue to be rationalized over increased production. Overhead recovered by the Company from drilling and construction activities increased in 2001 in accordance with activity but had a smaller impact on a barrel of oil equivalent basis due to increased production. General and administrative expenses, net of overhead recovered, decreased from $1.66 per BOE in 2000 to $1.03 per BOE in 2001. Modest increases are expected in general and administrative expenses in 2002.

Current Taxes and Interest Income

Current taxes are composed entirely of the federal Large Corporation Tax on capital as the Company is not currently taxable on income and does not have any operations outside of Alberta. In 2000, the Company incurred current income taxes of $150,262, but did not incur Large Corporation Tax, as the Company's capitalization at that time did not exceed the minimum threshold for the tax. Interest income earned increased during 2001, despite lower interest rates, due to larger cash balances throughout the year. On a production unit basis, interest earned decreased from $0.51 per BOE in 2000 to $0.32 in 2001.

Cash Flow

Cash flow from operations increased 89 percent to $4.1 million in 2001 compared to $2.1 million in 2000. On a barrel of oil equivalent basis, cash flow from operations decreased 20 percent from $26.69 per BOE in 2000 to $21.40 per BOE in 2001. Cash flow per share increased to $0.23 per share for 2001 versus $0.14 per share in 2000. The weighted average number of shares outstanding in 2001 increased 13 percent.

Depletion and Depreciation

Depletion and depreciation is determined on the unit of production method based on total proven reserves (based on prices and costs at the balance sheet date) with natural gas converted to a barrel equivalence using six thousand cubic feet equal to one barrel. Unproved properties are excluded from depletion and depreciation calculations and future development costs of proven undeveloped reserves are included in depletion and depreciation calculations. Unproved properties excluded from the calculation at December 31, 2001 were $860,000 ($674,000 in 2000) attributable to 47,112 net acres of undeveloped land at year-end. Future development costs of undeveloped reserves increased to $587,000 from $340,000 reflecting projects in progress at year-end.

Depletion and depreciation increased to $6.76 per BOE in 2001 compared to $5.10 per BOE in 2000. Depletion and depreciation increased, on a per unit basis, as a result of the higher costs of adding new reserves. The provision for future abandonment and site restoration costs, included in depletion and depreciation, increased to $0.28 per BOE from $0.17 per BOE in 2000 as a result of the increased number of producing wells in 2001. The provision for future abandonment and site restoration is determined by management in consultation with the Company's engineers and is based on prevailing regulations, costs, technology and industry standards. The total future liability is estimated at $520,000 at December 31, 2001 ($150,000 in 2000). Current expenditures for abandonment and site restoration of producing properties were nil.

Future Income Taxes

Effective January 1, 2000 the Company retroactively adopted the new CICA accounting recommendations for future income taxes; details of the retroactive adjustment are contained in the notes to the financial statements. The future income tax provision for 2001 increased to approximately $896,000 ($547,000 in 2000) due to the increase in pre-tax income. The Company has approximately $4.2 million of tax pools remaining at December 31, 2001 and, depending on commodity markets and the nature of expenditures, may be currently taxable in 2002.

Net Income

Net income increased by 58 percent to $1.9 million versus $1.2 million in 2000 primarily as a result of higher production levels, partially offset by lower prices and increased depletion charges. Net income per share increased 37 percent to $0.11 per share versus $0.08 per share in 2000.

Effective January 1, 2001 the Company retroactively adopted the new CICA recommendations on earnings per share, restating all prior periods to conform to the new recommendations. The Company now uses the treasury stock method for the calculation of diluted earnings per share under which the proceeds of the exercise of options are considered to be used to reacquire common shares at the average market price during the period. Previously, the imputed-interest method was used. As a result of this change in accounting policy, there was no significant effect on the current or prior year's diluted calculation of earnings per share.

Liquidity and Capital Resources

Capital expenditures of $7.8 million were financed through a combination of cash flow and proceeds from the issue of common shares. Common shares issued during 2001 included 25,000 resulting from the exercise of stock options and 2,300,000 common shares issued in private placements. Both private placements were composed of half flow-through common shares and half non flow-through common shares. These issues brought the total outstanding common shares to 19,361,886 at year-end.

At December 31, 2001 the Company had working capital of approximately $549,000 and unutilized bank facilities. The current bank facilities are $1.5 million subject to the annual review of current activities and reserves. The 2002 capital budget has been approved at $5 million and will be funded through a combination of cash flow and utilization of credit facilities. The Board of Directors reviews the capital budget throughout the year and adjusts it as justified by economic potential and financing capacity.

Business Risks

Exploration, development and production of petroleum and natural gas involve many risks that even the combination of experience and careful evaluation may not be sufficient to overcome. Utilizing highly skilled professionals, focusing in areas where the Company has existing knowledge and expertise or access to such expertise, using up to date technology, and controlling costs to maximize margins, mitigate these risks. The Company maintains a comprehensive insurance program that insures liability and property consistent with industry practice. The program is designed to mitigate risks and protect against significant loss. However, the Company is not fully insured against all these risks, nor are all such risks insurable.

Financial risks include exposure to fluctuation in commodity prices, currency exchange rates, and interest rates. To mitigate commodity risk, the Company maintains direct marketing control over its production. The Company enters into physical contracts for the sale of natural gas at fixed prices and terms and currently has fixed pricing arrangements as disclosed earlier. Although not currently utilized, the Company may institute financial hedging techniques for interest rates, currency exchange rates and commodity prices. If utilized, such transactions would be subject to certain limits on term and amount established by the Board of Directors.

MANAGEMENT'S REPORT

The accompanying financial statements and all information in the annual report are the responsibility of management. The financial statements have been prepared by management in accordance with Canadian generally accepted accounting principles. Financial statements are not precise since they include certain amounts based on estimates and judgements. Where alternative accounting methods exist, management has chosen those it deems most appropriate under the circumstances to ensure that the financial statements are presented fairly in all material respects. Management has prepared the financial information presented elsewhere in the annual report and has ensured that it is consistent with that in the financial statements.

Raven maintains systems of accounting and internal controls to provide reasonable assurance that assets are safeguarded and to facilitate the preparation of relevant and reliable financial information on a timely basis.

External auditors, appointed by the Shareholders, have examined the financial statements. The Audit Committee has reviewed the financial statements with management and the external auditors. The Board of Directors has approved the financial statements on the recommendation of the Audit Committee.

Sharon Supple

Laurie Smith
President & CEO
March 28, 2002

Sharon Supple
Chief Financial Officer

AUDITORS' REPORT TO THE SHAREHOLDERS

We have audited the balance sheets of Raven Energy Ltd. as at December 31, 2001 and 2000 and the statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2001 and 2000 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepting accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
March 28, 2002

BALANCE SHEETS

December 31	2001	2000
Assets		
Current Assets		
Cash and term deposits	**$ 2,144,115**	$ 1,325,238
Accounts receivable	**2,268,561**	1,484,679
Prepaid expenses and deposits	**198,838**	34,611
	4,611,514	2,844,528
Petroleum and natural gas properties *(note 2)*	**10,607,361**	4,022,935
	$ 15,218,875	$ 6,867,463
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	**$ 4,062,016**	$ 1,892,231
Future abandonment and site restoration costs	**67,300**	14,082
Future income taxes *(note 4)*	**3,087,485**	1,481,206
Shareholders' equity		
Share capital *(note 5)*	**5,290,306**	2,656,910
Retained earnings	**2,711,768**	823,034
	8,002,074	3,479,944
	$ 15,218,875	$ 6,867,463

See accompanying notes to financial statements.

Approved on behalf of the Board

David H. Erickson
Director

John D.G. van der Lee
Director

STATEMENTS OF INCOME AND RETAINED EARNINGS

Year Ended December 31	2001	2000
Revenue		
Petroleum and natural gas	$ 6,228,073	$ 3,480,421
Royalties, net of ARTC	(1,277,861)	(816,024)
Interest income	61,680	41,412
	5,011,892	2,705,809
Expenses		
Operating	739,858	272,262
General and administrative	195,967	133,606
Depletion and depreciation	1,286,400	410,610
	2,222,225	816,478
Income before income taxes	2,789,667	1,889,331
Income taxes *(note 4)*		
Current	4,667	150,262
Future	896,266	546,820
	900,933	697,082
Net income	1,888,734	1,192,249
Retained earnings (deficit), beginning of year	823,034	(369,215)
Retained earnings, end of year	$ 2,711,768	$ 823,034
Earnings per share – basic and diluted	$ 0.11	$ 0.08
Weighted average number of common shares outstanding	17,801,749	15,792,600

See accompanying notes to financial statements.

STATEMENTS OF CASH FLOWS

Year Ended December 31	**2001**	2000
Cash provided by (used in):		
Operating activities		
Net income	**$ 1,888,734**	$ 1,192,249
Items not involving cash:		
Depletion and depreciation	**1,286,400**	410,610
Future income taxes	**896,266**	546,820
Cash flow from operations	**4,071,400**	2,149,679
Change in non-cash working capital	**325,960**	(843,455)
	4,397,360	1,306,224
Financing activities		
Issue of share capital, net of issuance costs	**3,343,409**	1,007,739
Investing activities		
Petroleum and natural gas properties	**(7,817,608)**	(3,355,169)
Change in non-cash working capital	**895,716**	895,884
	(6,921,892)	(2,459,285)
Increase (decrease) in cash and term deposits	**818,877**	(145,322)
Cash and term deposits, beginning of year	**1,325,238**	1,470,560
Cash and term deposits, end of year	**$ 2,144,115**	$ 1,325,238

See accompanying notes to financial statements.

Supplemental cash flow information:		
Cash received (paid) during the year for:		
Interest income	**$ 60,680**	$ 41,412
Income taxes	**$ (152,320)**	$ –

Years Ended December 31, 2001 and 2000

1. SIGNIFICANT ACCOUNTING POLICIES:

The financial statements of Raven Energy Ltd. (the "Company") have been prepared by management in accordance with Canadian generally accepted accounting principles. The principal accounting policies followed by the Company are summarized below:

(a) Petroleum and Natural Gas Properties:

(i) Petroleum and natural gas properties

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized and accumulated in a single cost center representing the Company's activity undertaken exclusively in Canada. Such costs include land acquisition costs, geological and geophysical expenses, lease rental costs on non-producing properties, costs of drilling both productive and non-productive wells, related plant and production equipment costs, and administration costs directly related to these activities.

The provision for depletion and depreciation is determined on the unit-of-production method based on the estimated gross proven reserves as determined by independent engineers. Petroleum and natural gas reserves and production are converted into equivalent units based upon relative energy content. Costs associated with the acquisition and evaluation of significant unproved properties are excluded from amounts subject to depletion until such times as the properties are proved or become impaired.

The capitalized costs less accumulated depletion and depreciation are limited to an amount equal to the estimated future net revenue from proven reserves (based on prices and costs at the balance sheet date) plus the unimpaired cost of non-producing properties less estimated future administrative expenses, development costs, financing costs and income taxes.

Proceeds from the sales of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

(ii) Future abandonment and site restoration costs

Estimated future abandonment and site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs are estimated each year by management in consultation with the Company's engineers based on current regulations, costs, technology and industry standards. The annual charge is included in depletion and depreciation expense and actual abandonment and site restoration expenditures are charged to the accumulated provision account as incurred.

(iii) Joint activities

Substantially all of the exploration and production activities of the Company are conducted jointly with others and accordingly these statements reflect only the Company's proportionate interest in such activities.

(b) Income Taxes:

Effective January 1, 2000, the Company retroactively adopted the liability method of tax allocation accounting without restatement of prior years. Under this method, future income tax assets or liabilities are recorded on the difference between the financial statement and income tax bases of assets and liabilities using substantively enacted tax rates and laws. The future income tax provision is based on the change during the period in the related future income tax asset or liability accounts. As a result of the adoption, the Company recorded a decrease to retained earnings and an increase in the future tax liability of $377,477 as at January 1, 2000.

(c) Flow-through Shares:

The Company has financed a portion of its petroleum and natural gas exploration activities with flow-through share issues. The exploration and development expenditures funded by flow-through share expenditures are renounced to investors in accordance with tax legislation. The estimated value of the tax pools foregone is reflected as a reduction in share capital with a corresponding increase in future income taxes.

(d) Stock Based Compensation:

The Company has an equity incentive plan, which is described in Note 5 (d). No compensation expense is recognized for these plans when stock options are issued. Any consideration received on exercise of the stock options is credited to share capital.

(e) Earnings per Share:

Basic earnings per share are calculated using the weighted average number of common shares outstanding during the year. Effective January 1, 2001, the Company adopted the treasury-stock method for the calculation of diluted earnings per share under which the proceeds of the exercise of options are considered to be used to re-acquire common shares at the average market price during the period. Previously, the imputed-interest method was used. As a result of this change in accounting policy, there is no significant effect on the current or prior year's diluted calculation of earnings per share.

(f) Measurement Uncertainty:

The amounts recorded for depletion and depreciation of property, plant and equipment and the provision for future abandonment and site restoration costs are based on estimates. The ceiling test is based on such factors as estimated proven reserves, production rates, petroleum and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and changes in these estimates may impact the financial statements of future periods.

(g) Financial Instruments:

The Company periodically uses certain financial instruments to hedge its exposure to commodity price fluctuation on a portion of its petroleum and natural gas sales. Gains and losses on these transactions are reported as adjustments to revenue when the related production is sold.

2. Petroleum and Natural Gas Properties:

	2001	2000
Petroleum and natural gas properties, at cost	**$ 12,257,725**	$ 4,440,117
Accumulated depletion and depreciation	**1,650,364**	417,182
	$ 10,607,361	$ 4,022,935

Costs of unproved properties excluded from costs subject to depletion and depreciation at December 31, 2001 were approximately $860,000 (2000 – $674,000). Future development costs of proven undeveloped reserves of $587,000 (2000 – $340,000) were included in costs subject to depletion and depreciation.

Estimated future abandonment and site restoration costs to be accrued over the remaining life of the proved reserves are approximately $453,000 (2000 – $135,000).

3. Bank Facility:

The Company has access to a demand revolving facility of $1,500,000 from a Canadian chartered bank. The facility bears interest at bank prime rate plus 1% per annum and is secured by a general security agreement. As at December 31, 2001, the line of credit was unutilized.

4. Income Taxes:

(a) The provision for income taxes differs from the amounts which would be obtained by applying the combined federal and provincial income tax rate as follows:

	2001	2000
Income tax rate	**42.62%**	44.60%
Expected income tax provision	**$ 1,188,956**	$ 842,641
Increase (decrease) in taxes resulting from:		
Non-deductible crown payments	**315,287**	191,631
Resource allowance	**(482,065)**	(297,381)
Alberta Royalty Tax Credit	**(62,139)**	(41,204)
Future tax rate reduction	**(65,757)**	–
Large corporation tax	**4,667**	–
Other	**1,984**	1,395
	$ 900,933	$ 697,082

(b) The components of the Company's net future income tax liability at December 31, 2001 and 2000 are as follows:

	2001	2000
Petroleum and natural gas properties	**$ (3,125,057)**	$ (1,505,774)
Future abandonment and site restoration	**21,512**	4,710
Share issue costs	**16,060**	19,858
	$(3,087,485)	$ (1,481,206)

5. Share Capital:

(a) Authorized:

The authorized share capital consists of an unlimited number of common shares and an unlimited number of preferred shares, issuable in series. No preferred shares have been issued.

(b) Common Shares Issued:

	Number of Shares	Amount
Balance, December 31, 1999	15,044,886	$ 2,030,830
Issued on exercise of agent's option	200,000	20,000
Private placements for cash	1,792,000	996,000
Tax effect of flow-through shares	–	(385,344)
Share issue costs	–	(8,261)
Tax effect of share issue costs		3,685
Balance, December 31, 2000	17,036,886	$ 2,656,910
Issued on exercise of stock options	25,000	2,500
Private placements for cash	2,300,000	3,350,000
Tax effect of flow-through shares	–	(713,885)
Share issue costs	–	(9,091)
Tax effect of share issue costs		3,872
Balance, December 31, 2001	**19,361,886**	**$ 5,290,306**

(c) Private Placements:

During 2001, the Company completed two private placements. On July 4, 2001 the Company completed a private placement of 750,000 units at a price of $2.60 per unit, for gross proceeds of $1,950,000. Each unit consisted of one common share and one flow-through common share. Directors and officers of the Company subscribed for 115,000 units for consideration of $299,000. On December 28, 2001 the Company completed a private placement of 400,000 units at a price of $3.50 per unit for gross proceeds of $1,400,000. Each unit consisted of one common share and one flow-through common share. Directors and officers of the Company subscribed for 95,700 units for consideration of $334,950.

Total flow-through share issues during the year were $1,675,000. As at December 31, 2001, $675,000 has been expended as qualifying exploration expenditures. The Company is committed to spend the remaining amount of $1,000,000 on qualifying expenditures by December 31, 2002.

During 2000, the Company completed two private placements. On June 23, 2000, the Company completed a private placement of 264,000 units at a price of $1.50 per unit. Each unit consisted of one common share and two flow-through common shares. Proceeds totaled $396,000 of which $264,000 related to flow-through shares. On October 24, 2000, the Company completed a private placement of 1,000,000 flow-through common shares at a price of $0.60 per share for total proceeds of $600,000.

(d) Stock Option Plan:

Stock options to acquire common shares are granted to directors, officers, employees and consultants from time to time at exercise prices equal to the market value of the shares at the date of the grant. Options are granted for a five year term. Options granted to officers and directors vest immediately. The vesting periods for options granted to employees and consultants are determined by the Board at the time of the specific grant.

Options Outstanding	Number of Options	Weighted Average Exercise Price
Outstanding, December 31, 1999 and 2000	575,000	$ 0.21
Exercised	(25,000)	0.10
Granted	225,000	1.39
Outstanding, December 31, 2001	775,000	$ 0.56

The following table summarizes information about the stock options outstanding at December 31, 2001:

	Options Outstanding			Options Exercisable	
Range of Exercise Prices	Number Outstanding	Weighted Average Remaining Contractual Life (Years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$0.10-0.45	550,000	1.9	$0.22	550,000	$0.22
$1.25-1.40	225,000	4.5	$1.39	200,000	$1.40
$0.10-1.40	775,000	2.7	$0.56	750,000	$0.53

(e) Shares in Escrow:

At December 31, 2001, 4,174,522 (2000 – 7,487,823) common shares issued and outstanding are held in escrow and shall be released based on various time and performance criteria with written consent of various regulatory authorities.

6. RISK MANAGEMENT:

(a) Interest Rate Risk:

The Company is exposed to interest rate fluctuations on any outstanding bank indebtedness.

(b) Credit Risk:

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's petroleum and natural gas are subject to an internal credit review to minimize the risk of non-payment.

(c) Commodity Risk:

The Company may use certain financial instruments to hedge its exposure to commodity price fluctuations on a portion of its petroleum and natural gas production. At December 31, 2001, no hedging transactions were in place.

(d) Fair Value of Financial Instruments:

Financial instruments of the Company consist of cash and term deposits, accounts receivable, prepaids, accounts payable, and accrued liabilities. At December 31, 2001 there are no significant differences between the carrying value of such instruments reported on the balance sheet and their estimated market value.

CORPORATE INFORMATION

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Laurie J. Smith*
John D.G. van der Lee*

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